ILLINOIS COMMERCE COMMISSION

DOCKET NOS. 00-0259, 00-0395, 00-0461 (Cons.)

PREPARED REBUTTAL TESTIMONY OF

LEONARD M. JONES & MARK J. PETERS

SEPTEMBER 12, 2000

I. Introduction

1. Q. Please state your name, business address and present position.

A. (Mr. Jones) Leonard M. Jones, Manager of Business Planning and Forecasting, Illinois Power Company ("Illinois Power", "IP", or the "Company"), 500 South 27th Street, Decatur, Illinois, 62521.

(Mr. Peters) Mr. Mark J. Peters, Control Area Resource Manager, Illinois Power Company, 500 South 27th Street, Decatur, Illinois 62521.

2. Q. Have you previously submitted testimony in this proceeding?

A. Yes. We previously submitted exhibits identified as IP Exhibit 2.1 through 2.5. IP Exhibit 2.1 is prepared direct testimony containing questions and answers numbered 1 through 30.

3. Q. What additional evidence are you submitting at this time?

A. We are submitting IP Exhibit 2.6 as our prepared rebuttal testimony containing questions and answers numbered 1 through 27, and IP Exhibit 2.7.

II. Purpose and Scope

4. Q. What is the purpose of your prepared rebuttal testimony?

A. We will be addressing issues contained in the direct testimonies of Staff witness Zuraski, CILCO witnesses Lancaster and Munson, IIEC witnesses Bowyer and Stephens, New Energy witnesses Kagan, O'Connor and Bramschreiber, and Unicom Energy witness Braun.

5. Q. In his testimony Mr. Zuraski suggests (at p.29) that two "friendly allies" may choose to intentionally manipulate the market value of the index to their favor, and that given the limited liquidity of a market that such "private trades would not be diluted by observations of other trades included in the averaging process." Do you agree with such statements?

A. No. While we agree with the suggestion that it is harder to manipulate a deeper market, we disagree (1) with any implication that it is primarily the utilities who desire to manipulate the market downwards, and (2) with the notion that these private trades would not be diluted. In addressing the latter point, note that since the MVI calculation is an average of all observed and qualified values, the inclusion of any data point other than the "private trade" would necessarily dilute its impact. Since we sample multiple days, and do so 12 times a year, an entity desiring to manipulate the index would have to do so in each of the sample periods. Further, if they choose a contract in which other trades ultimately existed, they would have to keep making these fraudulent transactions at ever increasing levels to offset the diluting effect. Since these trades must be made in a forum which is guaranteed to be included in the index, their existence would be difficult to keep secret. Should a significant number of trades begin to be reported outside of the normal bounds of the "real" market, it would be noticed and inquiries would follow. Unlike the NFF report which cannot be challenged, a survey or published summary of trades can have its veracity questioned. If evidence of fraudulent trades exists, parties could approach various law enforcement bodies to request an investigation. For this reason, and those enumerated elsewhere, we believe the probability of manipulation to be inconsequential.

More importantly, this example seems to follow the form which has been hinted at in various forums - that is the suggestion that it is a "utility" that would attempt to bias the value, with the presumption being that utilities have an inherent desire to keep the market value below the actual market and therefore prop up TC's.

Unlike the customer or the ARES, the utility is only held harmless at the point in which the MVI and the resultant TC's are correct. It is clear that having TC's too low represents an economic loss for the utility. It must also be understood, however, that the utility does not benefit from having TC's too high, rather they face a multitude of costs.

The first of these is that customers who were forecasted to leave their incumbent bundled service utility supplier will not. The utility may have engaged in long term resource planning with the expectation of reduced supply requirements. They are now faced with the need to reacquire these resources at prevailing market rates, which may be substantially higher than the cost of the previously released resources.

Second, the utility collects no more revenue under the PPO if the MVI is correct, high or low due to the direct offset of the MVI error in the TC calculation. In the event that the MV used in the calculation of TC's is lower than actual market by more than the mitigation factor, the utility will be forced to serve some customers below cost, as is explained later. (It also should be noted here, that the issue of the utility collecting the same revenue under the PPO if the MV is too high is probably moot. Under this condition the TC's are too low, the utility is subsidizing competition and it would not be expected that many customers would then choose the higher cost PPO alternative.)

Third, unlike ComEd, Illinois Power is not allowed to collect imbalance charges from PPO customers, despite being required to provide them a credit for this value in the calculation of their TC.

Last, since TC's would be higher than appropriate, there will be a number of customers who become eligible for service under Rider PPO who would otherwise not be entitled to the service. This results in an unwarranted discount and could require the utility to serve a customer below cost. An example follows:

Simple Calculation of CTC

	MV Manipulated Downward	Correct MV
Customer Base Rate:	7.0	7.0
Market Value	4.0	6.0
T&D	1.5	1.5
Mitigation Factor	0.5	0.5
Transition Charge	1.0	(1.0) Less than Zero, Therefore Zero

Simple Calculation of PPO

Market Value	4.0	6.0
T&D	1.5	1.5
Transition Charge	1.0	-
PPO Rate	6.5	7.5
Savings Vs. Base Rate	0.5	(0.5)

Note: In the PPO calculation above, the column to the right represents the utility's cost to serve, not the customer's charge since a customer with 0 TC's is ineligible for PPO service.

As illustrated above, a customer that would not be eligible for Rider PPO if the market value were correct, can receive a 5 mil savings from the bundled base rates if the MV is manipulated downward. However, the actual cost to serve this customer is 5 mils higher than the customer's base rate. By manipulating the market value down by 2 cents the utility is experiencing an additional loss on this customer of 5 mils beyond what it was already suffering – and a customer who was already being served at rates below market receives an additional, unwarranted discount – at a rate no competitive supplier would be willing to offer.

Having said this, we believe that it is those who desire the market value to be too high that actually have the greatest impetus to attempt to manipulate the market. We believe the cost of doing so, both legally and financially, to be prohibitive.

6. Q. Is Illinois Power willing to adopt Mr. Zuraski's proposal to only utilize 4 price determinants in its Rider PPO vs. the current practice of price shaping the on peak hours?

A. No. Illinois Power believes this proposal is counter to both the need to maintain the same basis for PPO rates as is used in the TC determination and recent concerns that the market is suffering from a lack of demand management activities. By utilizing the same pricing structure for its PPO which is used for the establishment of the TC, not only is Illinois Power maintaining the integrity of the economics of the rate, but it is sending very definite pricing signals to customers, allowing them to further increase their savings (above the expected mitigation level) by operating in a manner which helps the reliability of the system. Under the ComEd/Ameren structure, once a customer's historical usage has been established, it may garner greater savings than expected by electing the PPO whenever it anticipates a shift in its long term production schedule. Conversely, a customer who implements a demand management program while on PPO will not realize near the benefit that they would under Illinois Power's structure.

More importantly, the PPO was never intended to be the primary means of competition within the state of Illinois as discussed by Mr. Breezeel.

III. Response to CILCO Witness Lancaster

7. Q. Does IP require a 15% Planning Reserve as suggested by CILCO in question 6 of the direct testimony of Deb Lancaster?

A. No. We have reviewed the relevant section of IP's Network Integrated Transmission Service ("NITS") application. CILCO's reference to the NITS application language is incorrect. Illinois Power's NITS application contains the following language: "MAIN currently suggests a 17 - 20% planning reserve margin of each year's maximum demand projection". While IP may believe the planning requirement is appropriate to help ensure system reliability, IP does not require the planning reserve for the purposes of providing transmission service to a customer.

IV. Response to CILCO Witness Munson

8. Q. Do you agree with Ms. Munson's characterization of the proposed indices as energy-only indices?

A. No. Ms. Munson's argument appears to be that, since the stated prices in the indices do not have an explicit value for capacity stated separately, this component must therefore be excluded. We strongly disagree.

It must be understood that the on-peak portion of the index, which accounts for approximately 75% of the level of the market value, represents firm contracts with liquidated damages. (It does not represent non-firm contracts.) Liquidated damages contracts, sometimes referred to as "Marketer Firm" or "Firm Energy", have become a standard trading product in the Midwest, and in particular through the broker market and electronic exchanges. Firm Energy refers to energy that will be provided to the customer unless there is a "force majeure" event. If the energy is not delivered to the customer and there was not a "force majeure" event, the supplier is required to make the customer financially whole for the replacement cost the customer incurs as a result of the supplier's failure to deliver energy. Firm Energy is generally delivered "Into" a control area rather than delivered to a specific transmission delivery point like Native Load Firm and System Firm are delivered. Since Firm Energy is delivered "Into" a system, the failure of a transmission path is not deemed a "force majeure" event and the supplier is still required to deliver the energy via another transmission delivery path.

The financial value of the Marketer Firm energy is equal to or greater than the financial value of Native Load power and energy. As explained above, the structure of Marketer Firm and Native Load products are different, thereby creating different requirements from a physical standpoint. Each product offers different advantages and disadvantages to the seller and purchaser. The argument to make an upward adjustment in the market value is based on the belief that the products are physically different. While we agree with assertions that the products have different characteristics or that one may have an explicitly stated capacity charge, we believe the more important consideration is the comparison of the risk and the associated market value of the two products. As described above, the supplier of Firm Energy is required to provide power to the customer unless a "force majeure" event has occurred, and should it fail to do so, it is required to make the customer financially whole by reimbursing the customer for any replacement power costs. The supplier of Firm Energy must maintain either an operational or financial reserve to protect against the loss of generation or transmission service. Native Load Firm and System Firm power suppliers maintain reserves designed to ensure the supplier will be able to serve load in all but one day in a ten year period (MAIN Guide 6, attached hereto as IP Ex. 2.7). If the Native Load or System Firm supplier curtails (System Firm) or proportionally curtails (Native Load Firm) as a result of system conditions, then the supplier does not incur any additional financial penalty. In addition, System Firm and Native Load Firm suppliers deliver power to a specific delivery point via a specified Firm transmission path. If the transmission path is curtailed, the Native Load Firm or System Firm power supplier is relieved of the requirements to provide energy. Since the supplier of Firm Energy has financial responsibility in situations in which Native Load Firm and System Firm suppliers do not, the financial value of Firm Energy is equal to or greater than the value of the Native Load and System Firm Products.

As such, while the values used to comprise the proposed index may not contain an explicit value for capacity, the value obtained appropriately reflects, and perhaps overstates, the value for power and energy.

9. Q. Do you agree with Ms. Munson's suggestion that the MVI must be adjusted for imbalances?

A. No. The Commission has already decided that imbalances are a delivery service and appropriately handled as such. Indeed, IP's Rider TC includes a provisions for energy imbalances as a component of delivery service in general, and more specifically, Transmission ancillary service. It is unclear what Ms. Munson hopes to accomplish by moving the calculation to the market value portion of the equation.

10. Q. Do you agree with Ms. Munson's assertion that IP's 12 monthly values causes customer's to make decisions quicker, complicates the customer decision making process and hinders competition?

A. We recognize that having market values calculated each month for the following 12 months may not provide customers with the leisure in which to review offers infinitum. However, we strongly disagree that this time frame hinders competition, and in fact believe that it promotes competition.

By continually updating market values for subsequent periods, the approach proposed by Illinois Power properly balances the need for accuracy with the ability of the retail market to function.

When the market value is only calculated once or twice a year, the potential for locking out competition is high should market values rise following the publication of the MVI/TC. Take for example a situation under the CE/Ameren proposal where the market value for the following summer, as calculated during March, is $150. This value is included in the calculation of TC's and customers are notified of these values. During negotiations with ARES' over the next 4-8 weeks, this summer value rises to $175. It is unlikely that an ARES would choose to serve these customers due to this dramatic increase in price. Rather, they would wait until the subsequent period B for new customers, while existing delivery service customers would be faced with either returning to bundled service or taking the PPO option. We have heard in many forums that the discrepancy between the NFF values and the actual market at the time that a customer decision is made created a situation whereby an ARES was unable to compete against the host PPO and that this was deemed anti-competitive. We see little difference between the NFF being wrong, and having a market value which was set 3 – 9 months prior to it being effective being wrong. Under, our proposal, the market value is established much closer to the period in which the customer's decision is effective and reset more frequently, thereby increasing the probability of the value being accurate and lessening the likelihood that a RES is locked out of competition.

Furthermore, the retail market is not supposed to be risk free for the ARES. By providing market values and the related TC's which do not change for 3 – 9 months, despite the obvious changes occurring within the market, the utility is being forced to accept an undue proportion of the risk of price changes. The ARES are not naïve, unsophisticated market participants. Rather, we believe them to be savvy, sophisticated participants, who have a wide range of risk management and forecasting tools available to them. Our proposal has been designed in a manner such that the most critical component of the calculation (the

5x16 On-Peak value) is the only component which changes on a monthly basis. This value is also the most actively traded and transparent component. ARES have wide ranging access to news services, broker exchanges and affiliated trading floors for gathering information on the trending of market values. By placing their forecast of market values into models they will develop to project the MVI, they can reasonably forecast a customer's TC. Utilizing these models and applying prudent risk management, there is no reason that they cannot enter into longer term negotiations with customers. We must not fail to lose sight here that a customer's TC is not independent of the underlying market value. Rather, they are inversely related. When the market price rises (and the ARES cost of supply increases) the customer's TC will fall. If an ARES is making a bundled offer, the customer's composite cost of service is virtually unchanged.

Just as the ARES are not naïve and unsophisticated, neither are many of the customers they are seeking to serve. The testimony here and elsewhere appears to characterize the average customer as timid, methodical and easily confused. It must be recognized that many of these same customers are those who are actively participating in the retail gas market and making supply decisions in time frames that are no longer, and often shorter than that proposed by Illinois Power. Further, many of these customers are involved in many other commodity purchases or make sales themselves. We do not believe it is reasonable to presume that they leave fixed price offers open for 3 – 9 months, without the expectation of a risk premium. Likewise, we find it unreasonable to expect host utilities to leave a fixed price offer (in the form of the Transition Charge) open for a similar period, without due compensation for the risk that we must bear.

Ultimately, the timing issue is one of risk management. As we are all aware, one of the greatest benefits of an active market is that those who are willing to accept risk, can take on the risk of those who are less willing to do so – for a price. What Ms. Munson and others are asking here by suggesting that IP should only update its market values annually, is to have IP assume an inordinate share of the risk of price changes – but not one has suggested that IP should be compensated in the form of an option premium for doing so.

V. Response to IIEC Witness Bowyer

11. Q. Do you agree with Ms. Bowyer's assertion (at p. 4) that "it is unlikely that the Cinergy forward price reflects an appropriate proxy"?

A. No. The Into Cinergy market, when appropriately adjusted for the basis differential between the regions, adequately represents the value of electricity applicable to the IP region. The Cinergy market is closely correlated to the Illinois Power region and transfers of energy between the two are not only possible but likely.

We dispute Ms. Bowyer's contention that prices at Cinergy cannot be reasonably translated to represent prices within Illinois Power. Staff Witness Zuraski's testimony and schedules supports the correlation of the two regions and the use of Cinergy as the appropriate location.

Ms. Bowyer lists five arguments to support her position. The first four of these issues, however, can be summarized as a concern of market manipulation. While electronic trading may only represent 2% of the current bilateral trades (although there is no direct evidence offered in support of this assertion), it cannot be assumed that these exchanges operate in a vacuum. These are tools for traders to use, and whether they passively monitor them (versus actively and aggressively utilizing them) does not lend credence to the suggestion of manipulation of the market. Traders are actively seeking opportunities to capture arbitrage. If an entity attempted to manipulate a market up or down on the electronic exchanges, it is not reasonable to expect the passive observer to ignore this opportunity. The electronic exchanges are an adequate representation of the underlying over the counter, bilateral market.

As discussed above, when one explores the mechanics and risk inherent in any attempt to manipulate the index, it becomes apparent that these concerns are grossly overstated.

VI. Response to IIEC Witness Stephens

12. Q. Has Illinois Power changed their opinion of the NFF process in light of the 2000 NFF report?

A. Yes, but not in the positive manner which Mr. Stephen's may want you to believe. We are even more concerned than we were before. Contrary to Mr. Stephen's presumptions, we do not believe that the NFF has corrected the fundamental problems existing in the 1999 report. First, in terms of the actual values, the NFF has exacerbated the problem by increasing the non-summer months on-peak value further above perceptions of actual market. While the NFF did increase the summer values, they did not do so to a level sufficient to resolve the problem that an ARES can not reasonably compete against these summer values. In our estimation, though the overall rate came up, by failing to solve the summer problem and worsening the non-summer issue, the 2000 NFF report is more problematic than the one presented in 1999. Second, IP continues to have grave concerns about the process as discussed by Mr. Breezeel.

VII. Response to New Energy Witness Kagan

13. Q. Do you agree with NewEnergy witness Kagan's assertions that the utilities' use of historical off-peak pricing does not reflect the market value for off-peak power and energy.

A. No. As has been argued by others, the relative lack of volatility over extended periods, in the historical price of the off-peak component, makes it a suitable proxy for the future price of the off-peak component.

14. Q. Do you agree with witness Kagan's characterization of the activities which determine daily spot market index prices?

A. Not completely. The statement (at p. 4) that "spot transactions are often based on the generators [sic] incremental cost since any load sold on the spot market will be incremental load on top of the load sold under longer-term contracts" could be true of any sale at any time. It would not be prudent to make sales below the incremental cost of generation. However, there are many conditions in which one would make sales at amounts well above incremental cost. The incremental cost of generation is only one of many components of the pricing determination. Other factors which cannot be ignored in this discussion include available, alternative supply and regional demand. Suggesting (at pp. 4-5) that "spot transactions are based on the incremental cost of generation, whereas longer-term transactions are based on the incremental cost of generation plus a contribution to fixed costs associated with maintaining the capacity to generate energy (*i.e.*, electric power) and a margin", without recognizing the impacts of forecasted, available supply and demand at any point in time, misrepresents the nature of the market. The statement is also making a presumption regarding the presence of a capacity premium in the off-peak period, which we do not necessarily agree with.

While arguably, spot power occasionally represents what Mr. Kagan has characterized as "dump" power, a similar argument can be made for any forward sale of energy for periods of low forecasted demand. As we all know, electric energy cannot be readily stored in a usable form. As such, market participants cannot buy low cost power in periods of low demand, store it and deliver it during periods of high demand (absent ownership of facilities such as pumped hydro storage). This also means that suppliers cannot sell excess energy into a market that is already saturated. Low demand periods, of which the 5x8 off-peak represents perhaps the lowest in a given temporal period, are typically viewed as buyer's markets, given the relatively high level of available supply and low regional demand. These markets saturate quickly. Given that consumers cannot purchase excess for storage, once the market is saturated, sellers cannot even "dump" power without jeopardizing the reliability of the grid by overgenerating.

As noted by Mr. Kagan, sellers may make sales to avoid cycling units. However, we believe that this is not solely a daily decision. Some units have operating parameters which may require them to stay off line for many days once cycled, or there are significant cycling and operational costs associated with ramping units up and down which may be incurred which encourage long term, stable unit operation. Given these costs and the possibility of the saturation of the off-peak market, sellers may in fact make long term sales nearer to incremental cost to ensure that their units will be utilized be during these periods.

Once committed to a longer term sale, the loss of a unit to the seller will necessitate that they either utilize another, higher cost unit, or purchase power on the spot market. Again, as noted by Mr. Kagan, a utility may "be seeking to find energy below its own incremental cost to avoid starting a unit." The sales price however, is not necessarily the incremental cost of the seller's unit. Rather, it will be somewhere between the seller's incremental cost and the buyer's avoided cost, and this range could be substantial, particularly when the buyer's avoided cost represents a change in fuel source, from nuclear to coal, or coal to natural gas. If the seller has already made long term sales for this period, their incremental cost for spot sales will be higher than that used for the original long term sales.

While off-peak is typically viewed as a buyer's market, the spot market reflects the real time operating conditions at the time of sale. As such, during periods of higher than expected demand, or when there is not an abundance of available supply, the market will tend to become a seller's market, with the associated premium.

15. Q. Do you agree with NewEnergy's proposal to add a premium reflecting a power or capacity value to the calculation of off-peak prices?

A. No. We do not believe that adequate evidence exists of a capacity value embedded within the sales price of long-term off-peak transactions. Capacity values are primarily embedded within the high demand, high volatility periods. Since the forward offpeak market is generally characterized by high levels of available, alternative supply and low forecasted regional demands, any attempt by a participant to extract such a capacity value in the off-peak component of a term transaction would be countered by other willing sellers. Many participants who purchase term off-peak power may be doing so as part of a larger, around the clock type transactions. In this type of transaction, it is the total cost, not necessarily the cost of an individual component which would be considered in accepting the proposal. The fact that there may be some form of capacity value assigned to the entire contract does not necessarily suggest that each hour of the contract contains an implicit value for capacity. A party for a wide variety of reasons may choose to structure the price components to meet some internal need and the other party may be indifferent as long as the total cost is acceptable.

16. Q. Do you agree with Mr. Kagan's description of how the three utilities are "shaping" forward prices?

A. While I believe Mr. Kagan accurately points out that a price shaping adjustment is being made, I do not agree with his characterization of the "Zuraski Adjustment". It is not our understanding that this adjustment attempts to account for "the fact that, in general, an alternative supplier will be a net seller during the relatively low-priced shoulder peak periods and a net buyer during the relatively higher-priced super-peak periods." Rather, this adjustment accounts for the fact that in general, spot market prices in a given hour within the 16 hour peak period are different than the average price during that period. In general, these prices are lower during low demand periods and higher during high demand periods. When this price shape is then applied to the actual load shape of a given customer or class, it helps to account for the additional cost of serving a customer or class who is taking more power during higher cost periods, while also providing a lower price to a customer or class who is taking more power during low cost periods.

We do not see where the status of an ARES as a net buyer or seller has any bearing on this adjustment.

17. Q. Do you agree with Mr. Kagan's assertion that there must be an additional cost added to the MVI to account for the customer's load uncertainty?

A. No, because the price shaping adjustment which is already performed within our Rider TC, when applied to the customer's or class' load shape already adequately accounts for this variability.

Mr. Kagan has only suggested that the ARES bears an additional cost associated with the risk of the customer's load variability. He has ignored the fact that the customer by signing a fixed price contract with the ARES bears a similar risk – which is in fact a potential benefit for the ARES. Mr. Kagan properly points out that a "retail customer can consume as much or as little electricity in each hour subject only to physical constraints." What he has failed to do is demonstrate that the customer's consumption in a given hour has any basis in the market price of power in that same hour.

While it is true that an ARES must supply whatever demand a full requirements customer of theirs presents in a given hour, regardless of current market price, it is likewise true that a full requirements customer must pay the ARES the agreed upon price for all energy they take in that hour, regardless of market price. While on the surface that may sound redundant, it is the presentation of the fact that the ARES holds a PUT option against the customer, just as the customer holds a CALL option against the ARES. So, for every instance in which a customer takes more energy from the ARES than originally forecasted, during an hour in which the ARES' cost for such power is above the forecasted cost basis of the contract, there may be an hour in which the customer either takes less in a higher cost (to the ARES) hour, or more in a lower cost (to the ARES) hour.

18. Q. Do you agree with Mr. Kagan's proposed use of the Black's model for pricing such an option?

A. No. First, as discussed above, we do not believe that any optionality adjustment is warranted.

Second, the use of the Black's model here is inappropriate. While widely used in the financial markets, and used to some extent (the level to which is very debatable) within the energy markets, Black's has a fundamental assumption of optimal exercise of the option. That is to say that the model assumes that the holder of the option will exercise the option every time that the exercise price of the option is "in the money". That is a critical component to its valuation methodology. As discussed above, full requirements energy customers with other than real time pricing contracts, are not making their consumption decisions based upon the spot price of electricity. The fact that they consume more than originally forecasted during an hour in which energy prices exceed the strike price of the option is happenstance – especially so for any customer (i.e. industrials) whose load is not weather sensitive. Mr. Kagan's assertion (at p. 12) that the customer holds a "more restrictive and less valuable option, because" they "only exercise the option indirectly through changes in consumption" is only partially correct. It ignores the fundamental fact that this change in consumption is not influenced by the spot market price of electricity. His proposal to reduce the value of the option by 25% to 50% is insufficient to overcome this fundamental flaw in the use of the Black's model for an option which cannot be argued to be executed in anywhere near an optimal manner.

Just as the Black's model assumes optimal exercise, it also assumes a fixed, defined block of the underlying commodity. Since the customer's load can vary from zero to the maximum physical capability of their connected load, there cannot be a fixed block assumption made in the valuation of the option.

Next, Black's model requires an accurate assumption of annualized price volatility. The current source of this data is primarily proprietary historical data compiled by various trading floors. These numbers and the resulting implied volatilities, are not uniform across the industry. In fact, many options traders specifically trade the implied volatility component – believing their models and assumptions to be more correct. There is virtually no auditable, public data source for real time transactions from which to develop a uniform volatility assumption.

Last, the adoption of any credit for the call option held by the customer against the ARES must be offset by the value of the put option held by the ARES against the customer.

In sum, we do not agree that an "optionality" adjustment should be made in this case.

VIII. Response to New Energy Witnesses O'Connor and Bramschreiber

19. Q. Do you agree with the assertions of NewEnergy Witnesses O'Connor and Bramschreiber (at p.8) that "the proposals, among other things, provide equal recognition to the value utilities can buy power and energy, thereby artificially depressing market values and artificially inflating transition charges"?

A. No. The proposals provide equal recognition to the value of transactions within the market, regardless of counterparty. We know of no basis for the presumption that the inclusion of a purchase by an entity which happens to be a utility as opposed to the same purchase by an entity who happens to be a power marketer artificially depresses market value. An actual transaction requires the willing participation of two parties – the buyer and the seller. Additionally, there has been no proof offered that the price that a utility may pay for power and energy does not in fact have the impact of increasing the market value. Indeed, given the obligation to serve and planning/operating reserve requirements for which utilities are responsible, it is likely that certain utilities are net buyers of power, and may have a greater willingness to cover any potential short fall than other market participants. This willingness to quickly consummate a trade may be further exacerbated if the utility making the purchase was able to pass on the additional cost of this purchase to their bundled service customers through the use of a Fuel Adjustment Clause.

20. Q. Do you agree with NewEnergy Witnesses O'Connor and Bramschreiber (at p. 10) that in regard to off-peak values the proposals "do not adequately reflect the value of *power* associated with longer-term transactions"?

A. No, as stated previously in regard to Mr. Kagan's testimony, we do not believe that there is adequate evidence that a value for power even exists for the off-peak power.

21. Q. Do you agree with NewEnergy that a price adjustment is necessary due to the requirements of Illinois Power's and Ameren's Transmission Services organizations in regard to the procurement of designated network service?

A. No. We can find no evidence with NewEnergy's testimony that there is a price differentiation between the Marketer Firm product included in the calculation of the Market Value Index and a native load firm product. As discussed in our rebuttal of CILCO witness Munson, we believe that the value of Marketer Firm is equal to or greater to that for Native Load Firm. Without better evidence of a price difference (Native Load Firm greater than Marketer Firm), we see no basis for making such an adjustment.

22. Q. Do you agree with NewEnergy's support of the Into ComEd over the Into Cinergy plus a basis adjustment?

A. Yes, but at most only for ComEd. In ComEd's case it may be appropriate to use an unadjusted value which already represents the value of the market in which they are located. However, for all utilities other than ComEd, a basis adjustment is necessary whether into ComEd, into Cinergy, into Entergy or anything other than an into IP or into Ameren is used. Since there is no viable, into IP or into Ameren available, it is apparent that the best available location should be selected, and a proper basis adjustment be made. As is supported by the testimony of Staff (Mr. Zuraski at p. 24) that the into Cinergy hub is superior to the into ComEd hub in terms of liquidity and number of market participants. For these reasons, into Cinergy is more relevant to Illinois Power and Ameren than into ComEd.

Additionally, NewEnergy stated that "NewEnergy previously objected to the use of a non-representative market index"(at p. 14). We also object to the use of a non-representative market index and assert that Into ComEd is a non-representative market index for utilities in Illinois other than ComEd itself.

IX. <u>Response to Unicom Energy Witness Braun</u>

23. Q. Do you agree with Mr. Braun's assertion that "the marketplace for electricity in Illinois is best served by a single base index", that it is more efficient for an ARES to have a single base index and that is allows customers to more easily shop for electricity?

A. No. The marketplace is best served by having accurate values for each utility. If this happens to be accomplished through the use of a single base index, then we would support this. However, we maintain that the unadjusted price of power and energy within the ComEd hub is not appropriate for use in the balance of the State. As stated elsewhere, regardless of the hub chosen, it is necessary to properly account for the basis differential between the locations.

Mr. Braun's argument of reduced burden for ARES and a supposed benefit to customer's ease of shopping, cannot outweigh the inherent error of not basing the market value for a utility upon the market applicable to that utility. Again, it appears that the risk of this error is expected to be borne by the utility alone. It is notable in this instance, however, that Unicom's regulated affiliate ComEd is not affected by this proposed change.

24 Q. Do you agree that the Into ComEd is the best source for Illinois?

A. No. It may be arguably a better selection for use by ComEd itself, if the issues of market domination and illiquidity raised by the IIEC, Staff and others can be properly addressed. To state (at p. 5) that "the Into ComEd market is the most liquid Illinois market" places unwarranted value on an Illinois market versus any other interconnected or easily translatable region. What is important is not the state or states which a hub may cover, but whether the market value at that hub accurately represents the market value for customers within a given utility's service region. Mr. Braun himself states (at p. 3) that "(t)here are two main elements that any methodology should have: transparency of data and accuracy." In this respect, the Into ComEd falls woefully short of the Into Cinergy as an accurate representation of prices for IP and Ameren.

Given (1) the general acceptance by witnesses in this case that the Into Cinergy hub is a much more viable trading location than Into ComEd in terms of liquidity and participants, (2) there has been no evidence or testimony presented here that the Into Cinergy market basically represents the view of a single participant as has been suggested with the Into ComEd (Staff Witness Zuraski page 26, line 507: "In fact, ComEd manufactured the on-peak forward price data upon which its first Applicable Period A index was based.", NewEnergy witnesses O'Connor & Bramschreiber page 14, line 13 "NewEnergy does have concerns with…..the large number of postings that are made by ComEd itself.") and (3) the need to translate any non-IP or non-Ameren index to make it applicable for use by those utilities – including Into ComEd, we strongly disagree that ComEd is the most suitable source for all utilities in the State of Illinois.

25 Q. Does Illinois Power believe that its 12 monthly calculations will require ARES to add staff or forego opportunities?

A. While Illinois Power obviously cannot speak to the marketing strategy or staffing of any other entity, we would suggest that the Illinois Power proposal may actually provide ARES with a more relaxed marketing cycle, since rollover activity will not be compressed into a single month, as it is with the ComEd and Ameren proposals. Under the ComEd and Ameren proposals, once a customer goes onto delivery services they will necessarily have their next TC calculated the following spring, to be effective in June. As such, all delivery services customers will have their TC's reset in the same month. It is reasonable to expect this to create an ever increasing bubble in the marketing efforts of any ARES. Each year, all of that ARES' customers will need to be renegotiated, all within the same time frame if the ARES feels that they can only make decisions once they have absolute certainty of the MVI and TCs. Under the Illinois Power proposal, customer rollover dates will be distributed throughout the year. There will not be a concentration of all the customers within a single period.

As stated elsewhere, and within our direct testimony, ARES should be capable of monitoring the market and forecasting the impact of market trends on subsequent period MVI's. To suggest that the ARES are not sophisticated enough to perform this analysis or properly manage any associated risk, but rather that they require absolute certainty of the results before they can act, minimizes the capabilities of these organizations and flies in the face of the existing risks that they may already manage in the wholesale markets.

Nor does Mr. Braun's contention appear to represent the consensus among the ARES. In fact, it is diametrically opposed to the position stated by Nicor witness Bailey, in his testimony (at p. 4) "the 12 month rolling calculation appears to be better for marketers and customers, as marketers can better price on a one year basis, and customers are better able to see consistent savings throughout the year."

26 Q. Do you wish to comment on Mr. Braun's assertion that a one month delay in the publication of the MVI is an appropriate compromise?

A. Yes. Again, the proposal is to shift an unacceptable proportion of the risk of price changes onto the utility. It must be understood that in the event that prices fall following the publication of the MVI, the utility is required to absorb the difference between the new market value and the value used to create the MVI. If the prices were to rise following publication, the utility does not receive a benefit as the customers will not leave their system, rather they will merely elect the PPO as has been evidenced in 2000. They will make no more from a customer on the PPO in this case than they would have if the customer had elected choice with a valid market value. In fact, since Illinois Power, unlike ComEd, is currently precluded from collecting imbalance charges from its PPO customers, (despite having to give the customer an imbalance credit in the calculation of TCs), it can be argued that we actually suffer a loss over what we would have collected.

Mr. Braun's base assumption, as he confidently puts forth on page 8, line 21, is that the market cannot change that much in one month. Such an assertion is naïve at best and disingenuous at worst. One need only view the market value for the July/August 2000 contract between May 1, 2000 (Approx. $157 according to various publications) and May 31, ($185 bid at $220 offer), to recognize that this statement is false. It is important to note here that, in this instance, had Illinois Power's MVI been effective, but utilizing the one month delay suggested by Mr. Braun, the ARES would have been potentially locked out of serving customers for the summer due to this substantial increase in price.

27. Q. Does this concluded your prepared rebuttal testimony?

A. Yes, it does.